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INVESTING IN AND FINANCING THE HYDROCARBON SECTOR TO ENHANCE GLOBAL ENERGY SECURITY

Note by the secretariat

Summary

Investing in future energy sources to meet growing demand will be a key challenge in securing future security of energy supply. This note reviews the sources of funding for energy investments and evaluates what is required to match those funds with developing energy needs. Emphasis has been placed on what role governments, national oil companies, and investment policies play in facilitating (and impeding) investment in future energy supply.

During the sixty-second session of the Commission held in April 2007, the panel on "Sustainable energy policies: the key to energy security" urged the Committee to undertake a broadly shared intergovernmental expert dialogue on energy security specifically in the area of energy infrastructure investment and financing. It was also recommended that this enhanced technical dialogue on energy security be conducted during the annual sessions of the Committee with the participation of representatives of governments, energy industries, the financial community and relevant international organizations. This note been prepared on that basis so as to provide the Committee with the necessary background information to enable in-depth consideration of the issue and hence to make any decisions or otherwise on future work.

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I. INTRODUCTION

1. Securing future security of energy supply is a global challenge. In turn investing in future energy sources to meet growing energy demand will be a key challenge. The current high-commodity price environment makes many energy investments look attractive. However, the historically cyclical nature of the hydrocarbon markets suggests that investors should proceed with measured enthusiasm. A shifting focus from private sector to public sector ownership of assets, as well as from established to emerging markets, will add further challenges to future development.

II. MARKET TRENDS

2. Rising Demand for capital investment: The industry will have increasing capital requirements over the next 10 years to develop new capacity and increase existing capacity. High levels of liquidity among both equity and debt investors signal that there remains sufficient capital in the present market to continue funding this expansion. Ensuring security of future supply, however, will depend on the efficient allocation of available capital.

3. Geographical trends in the energy value chain: Upstream, midstream, and downstream activities in the energy industry will migrate towards the regions and markets in the best competitive position. Investment in the value chain, especially oil and gas, will continue to thrive in the Middle East, given the region's low cost and abundant amount of feedstock, as well as the increasing availability of private financing to establish world-scale plants. Energy consumption will remain at high levels in the developed North American and European markets, while high feedstock prices (coupled with environmental concerns) in these regions will continue to push production and processing towards other markets.

4. Divergence in private sector participation: Certain emerging market countries are developing (or have developed) major energy sector reforms, including a significant privatization of state assets and the opening of energy development to private investors. These new investment laws and regulations are based on the recognition that to substantially increase capacity, the governance framework and investment climate in the region need to be improved so as to make it possible to attract private investment and foster regional competition.

5. In the larger context of natural resources, particularly in upstream development, a strong pattern of growing state control has taken shape. National Oil Companies (NOCs) now exert a dominant control over reserves and production, raising the question of whether their interests are aligned with the broader goal of securing the future supply of energy.

III. SOURCES OF FUNDS

A. Sponsors / Equity Investors

1. Strategic Investors

6. A large majority of energy projects are developed by "Strategic Investors", which, for the purpose of this paper, are defined as companies existing within the energy sector with significant

experience or investment in one or more links of the energy value chain. Strategic Investors fall generally into one of two categories: International Oil and Gas Companies (IOCs) and NOCs.

7. For much of the twentieth century, the upstream oil and gas industry was dominated by IOCs exploring for and producing resources in select production regions around the globe. During this period, most oil and gas-rich regions were open to investment by private sector developers. In the 1960s, for example, it was estimated that 85 per cent of oil and gas projects globally were open to equity investment.[1]

8. Over the past 30 years, dominance in the upstream oil and gas industry has been shifting away from IOCs and towards NOCs. Today, the NOCs control over 70 per cent of world oil and gas production and nearly 95 per cent of world oil and gas reserves.[2] Among the NOCs, a handful of companies – Saudi Aramco, Gazprom, CNPC of China, NIOC of the Islamic Republic of Iran, Petróleos de Venezuela S.A. (PDVSA) of Venezuela, Petrobras of Brazil, and Petronas of Malaysia – control over 30 per cent of world oil and gas production and reserves.

9. In the context of security of energy supply, this shift in dominance from IOCs to NOCs may have an impact on the required growth in production to meet growing demand. IOCs are large, publicly traded organizations, whose ultimate goal is to maximize shareholder returns through optimizing investment in future production. The ultimate goal of NOCs is less clear and varies from country to country; as a state-sponsored and funded organization, the NOC may pursue an investment programme that takes into account political and security considerations in addition to commercial success. Furthermore, the profits made by NOCs are not necessarily reinvested into securing future production.

2. Private Equity

10. In recent years, the growth of the private equity investor class has created a new subset of equity sponsors in major energy and infrastructure projects. Infrastructure assets, in particular, are being increasingly recognized as an ideal vehicle for the diversification of risk, as they are partially insulated from historically cyclical returns of many other investment categories. In addition, the long-term lifecycle of infrastructure assets closely matches the long-term investment periods that are sought by most institutional investors.

B. Sources of Debt

11. Debt for energy and infrastructure projects comes from a number of sources: commercial banks, the capital markets, export credit and multilateral agencies, and most recently Islamic finance institutions.

1. Commercial Banks and Capital Markets

12. The commercial banking market provides debt in the form of bank loans to companies or even directly to projects. Commercial banks are usually the first place for sponsors to look to

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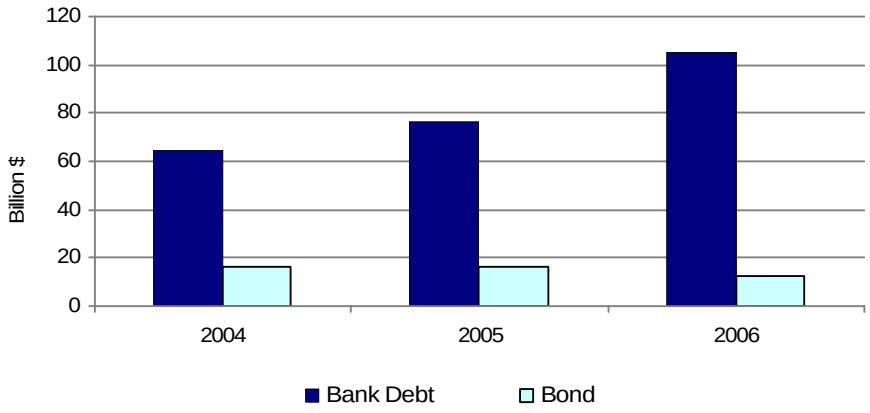
[1] Oil companies adjust as government roles expand. The Oil and Gas Journal
[2] OGJ, 4/9 and 18/12 of 2006; IEA 2006 WEO; SAIC Analysis

raise debt financing for an energy project. Globally, high levels of liquidity and increased competition between a growing number of banks around the world have pushed down lending rates, making commercial borrowing more attractive. When lending to projects in emerging markets, most banks require political and commercial risk guarantees from government or multilateral sources of financing in order to provide loans at reasonable interest rates and long tenors. Figure 1 highlights the nature of the project finance lending market between 2004 to 2006.

Figure 1: Project finance lending market



Source: Project Finance International

13. The capital markets have played a secondary role in financing major midstream energy projects. Due to the complications arising from having multiple creditors represented through a bond agent, as well as "negative carry" costs arising during the construction period, capital market placements are often left to "cookie-cutter" projects with a tried and tested methodology selling into a highly liquid, established market.

2. Export Credit and Multilateral Agencies

14. Export credit agencies (ECAs) are governmental or quasi-governmental institutions established for the purpose of promoting the respective country's exports. ECAs encourage exports by providing direct loans or loan guarantees for the purchase of goods and services by customers in countries in which there is limited availability of private commercial debt financing. The ECAs approached for financing a project will depend largely on the choice of the Engineering, Procurement, and Construction (EPC) contractor and the procurement strategy since the funding is tied to the country of origin.

15. Export credit agencies are a crucial segment of the emerging market project debt markets, in that they are able to provide additional capacity and valuable insurance cover to capital-intensive projects. ECAs can provide either direct loans or loan guarantees (some ECAs provide only loan guarantees). There are two types of guarantees:

(a) Political-risk-only, in which case the ECA assumes the risk of payment defaults caused by political risk events, such as expropriation and political violence.

(b) Comprehensive, in which case the ECA would assume both commercial and political risks.

16. ECAs charge a premium (paid up-front or during the construction period and financeable) for assuming commercial or political risks associated with the loan. The key factor in determining the level of premium charged is the country risk associated with the borrower. In an industry that continues to expand in the developing world, political risk insurance, in particular, is vital in getting many projects financed.

3. Islamic Finance

17. Rapid developments in the Middle Eastern banking sector have led to a growing supply of Islamic finance, as Middle Eastern institutional investors look to reinvest in Sharia-compliant investments. Demand for Islamic finance has risen in parallel, as borrowers look to add additional capacity and to optimize multiple pools of liquidity. Sharia law prohibits charging interest on loans, so most Sharia-compliant instruments are structured in such a way that the lender is taking some asset or ownership risk. Types of Sharia-compliant debt products include:

(a) Morabaha – Cost-plus financing
(b) Ijara – Leasing
(c) Mukarada – Revenue Bond
(d) Salam – Forward Purchase
(e) Istisna' – Variation of Morabaha in which financing is procured during the construction phase
(f) Sukuk – Bond.

IV. FOLLOWING THE ENERGY CHAIN

A. Extractive Industries

1. Attracting Upstream Investments

(a) Role of IOCs, NOCs and Governments

18. In a US$ 70/barrel world, IOCs have developed a healthy appetite for risk, and are at present generally open to investing in nearly any region of the world. However, the historically cyclical nature of the hydrocarbon industry portends a period when the private sector will be more risk averse towards investing in new developments.

19. There have recently been a number of high-profile incidents in which the host government, acting alone or in unison with its respective NOC, has affected foreign direct investment through a change in licensing terms, breach of contract, or expropriation. Such incidents have occurred in several countries including Algeria, Bolivia, Russian Federation and Venezuela.

20. Although these incidents may not appear in the present market to have dampened the investment appetite of IOCs, a change in market conditions will no doubt make life difficult for those countries that are generating a negative legacy of foreign direct investment (FDI). For countries such as Saudi Arabia and the Russian Federation, which have developed seasoned NOCs, the technical capacity to develop future supply may not pose as great a problem for the development of future resources. However, for countries such as Venezuela, whose NOC PDVSA lags behind IOCs in technical capacity to develop new resources, developing new, technically challenging projects without the support of the private sector will pose an impediment to maintaining and expanding capacity.

21. Regardless of technical capacity, leaving a negative FDI legacy will not only drive away private sector equity investors, it can also adversely affect a country's ability to raise debt financing for its own NOC's oil and gas developments. Though debt financing plays as less significant role in upstream development (as discussed below), creating a negative FDI legacy in upstream investments will hinder a country's ability to raise financing further down the value chain.

(b) Taxing Production: Production-Sharing Contracts versus Royalty Regimes

22. Instituting an appropriate tax structure for the development of the natural resources industry is a tool by which the host government can effectively attract (and dissuade) foreign direct investment. Historically, the upstream oil and gas sector has been taxed through royalty payments and corporate profit taxes. Towards the end of the twentieth century, host governments (particularly in the emerging markets) began instituting production sharing agreement (PSA) schemes, whereby upstream investors are compensated for project and political risk through back-ended taxing mechanisms, allowing them first to recoup certain capital and other expenses before sharing the "upside" with the host government.

23. PSAs proved to be a strong incentive in attracting foreign investment to markets with heightened levels of risk. However, recently many host governments have begun to push back, claiming that many PSA structures unfairly deprive the host government of tax revenue. Typically, complaints arise when capital costs exceed project estimates. In this scenario, the period of cost recovery is automatically extended, pushing back revenue realization for the government.

24. Some governments, such as the Russian Federation, have moved away from the PSA model in favour of a royalty regime, in which a tax is charged on the market value of the commodity produced. Such a tax scheme is beneficial to the host government in that tax revenue is realized immediately after the project begins to operate.

25. Instituting an appropriate tax regime for the specific country or region is important to attracting foreign direct investment; however, adhering to the tax policy once it has been instituted has proven to be just as important in attracting and retaining foreign direct investment.

2. Methods of Financing Extractive Industry Projects

26. Upstream financing methods are limited, due to the inherent high risks unique to upstream exploration projects. Debt providers, in particular, are reluctant to take the risk associated with a new reservoir where the existence of oil or gas has been postulated on the basis of seismic data alone, and a commercial development has yet to be demonstrated by drilling. For this reason, most upstream exploration investments are financed on balance sheet, and debt financing, if any, is raised at the corporate level.

27. Once a reservoir has been delineated by drilling, the sponsor has more financing options. A popular approach among smaller producers without ready access to corporate borrowing is to raise non-recourse debt against the proved reserves (P1) in a field or group of fields to cover a proportion of development costs. In this reserve-based lending (RBL) approach, the lender bank or, for larger projects, a consortium of banks estimates the discounted future cash flow to be generated from the P1 reserves and applies a cover ratio (either a reserve life or loan life cover ratio). By dividing the discounted P1 cash flow by the applicable cover ratio, the lender bank is able to size its loan. The outstanding facility is adjusted as the field is developed; as more P1 reserves are proved up, the amount of debt that the sponsor can borrow increases. In a similar fashion, once the field starts producing, the sponsor is required to repay the facility from sales revenues in order to maintain the required cover ratios.

28. The benefits of RBL financing include:

(a) Enhanced borrowing capacity: An RBL is backed by the underlying asset, not by the sponsor's balance sheet. A smaller developer with limited corporate borrowing capacity can gain greater leverage to help finance future development.

(b) Dynamic structure: As the field is developed, the sponsor is able to draw down, repay, and redraw on the facility as funds are required, provided that estimated future cash flows meet the specified cover ratio test.

29. Drawbacks of RBL financing include:

(a) Capacity limitations: Most banks will lend non-recourse against only the P1 reserves, whereas development decisions (and hence capital investment costs) are generally based on P1+P2 (proved plus probable) reserves. If the facility is to be used towards financing a field with a large P2/P1 ratio, the proportion of development costs that can be borrowed may be severely limited.

(b) Cost of facility: Depending upon the location and geological features of a particular reservoir, the fees and spread charged by the lender bank on an RBL may add up to a borrowing cost that exceeds the corporate borrowing costs of the sponsor.

30. Employing a volumetric production payment (VPP) structure is an alternative approach to financing proved, developed, and producing (PDP) resources. In a VPP contract, the producer forward sells the PDP production of the field, and receives a one time payment based on the estimated discounted value of the field's cash flows. A VPP acts both as a type of synthetic loan

– in that the forward sale is paid for upfront – and a hedge as the estimated cash flow is determined by applying a forward price curve agreed upon by the two parties.

B. Midstream and Downstream - Power, Refining, Transport, and LNG

31. In comparison to upstream projects, midstream and downstream investments are characterized in general as having larger capital requirements and longer investment horizons.

1. United States of America and Europe

(a) United States Electric Power

32. The International Energy Agency (IEA) estimates that from 2005 to 2030, the United States will require 750 gigawatts (GW) of capacity additions (and replacement capacity) to meet expected demand. Total investment required to meet this growth is estimated to reach US$ 794 billion for generation alone (US$ 1.6 trillion including transmission and distribution), equating to approximately US$ 30 billion per year in investment.[3]

33. Regulated utilities, which constitute 62 per cent of the United States power market, have traditionally resorted to municipal bond financing to fund capital developments. Between 2000 and 2004, over US$ 60 billion in municipal bonds were issued for electric power facilities. Due to the depth of the capital markets and the historic strength of the regulated markets in the United States, availability of financing should not pose an impediment to future development.

34. In the private sector, Independent Power Producers (IPPs) went through a period of difficulty starting in the late 1990s because of increased capital investment, higher fuel prices, and increased interest rates. The collapse of the merchant power market limited the bank market's appetite for independent power. Over the past few years, the power market has slowly rebounded, and IPPs have begun to invest in expanding capacity as shown in Figure 2. Due to liquidity and appetite in the high-yield markets, IPP developers have been able to raise capital more easily thanks to having recourse to traditional project finance debt.

(b) European Union Electric Power

35. Between 2005 and 2030, the IEA estimates that Europe will require 928 GW of additional and replacement capacity, costing an estimated US$ 1 trillion (US$ 1.7 trillion including transmission and distribution).[4] Given the large capitalization of European banks and their historical relationship with the power sector, utilities in Europe have relied primarily on bank debt to supply additional capital for capacity growth.

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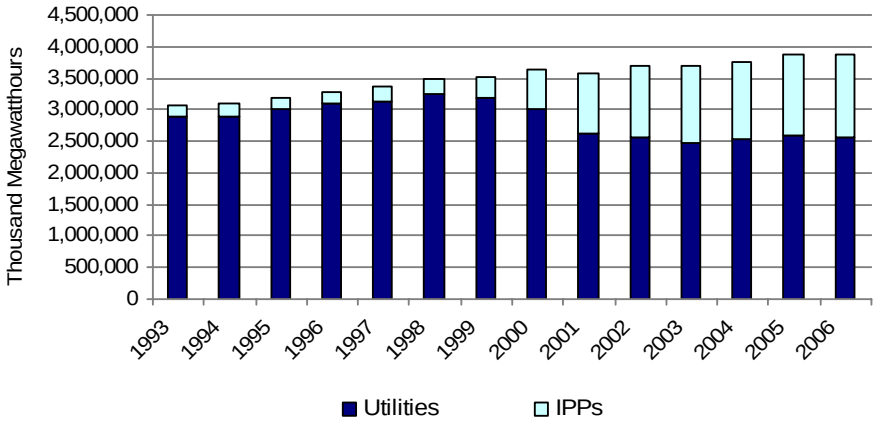
[3] IEA World Energy Outlook 2006, p149
[4] Ibid

Figure 2: United States generation: utilities and IPPs



Source: United States Energy Information Administration (EIA)

(c) Renewables

36. The renewables markets in both the United States and Europe have undergone significant expansion in the last decade, due in large part to increasing government policy-driven subsidies and tax credits. Renewables will no doubt play an important part in the growing United States and European power markets, but both regions will continue to rely largely on fossil fuels (and nuclear power) for the production of electricity.

(d) Refining

37. Refineries are a crucial link in the energy chain, serving as the conversion point between upstream resources and end market products, which often can be regulated or face challenges in pricing. Historically, thin margins in the refinery sector and volatile energy prices have led to lags in investment. The IEA estimates that from 2005 to 2030 the North American oil refining sector will require US$ 100 billion in new investment, or approximately US$ 4 billion a year. During the same time period, it is predicted that OECD Europe will require approximately US$ 30 to US$ 35 billion.

38. In the United States, expansions of existing refineries have been able to plug the gaps in capacity, and companies with existing refineries will continue to look towards adding capacity at existing sites, due to economies of scale and a relatively easier regulatory burden. It is anticipated that select greenfield developments will be required to fill in regional shortfalls of supply. Due to escalating capital costs reaching upwards of US$ 17,000 barrel per day (b/d) capacity (or approximately US$ 4.3 billion for a 250,000 b/d plant), even the largest midstream companies will look beyond balance sheet financing for additional sources of capital. For a multi-billion dollar greenfield development, project sponsors will most likely tap the bank markets, and potentially capital markets, for additional funds.

(e) Pipelines: United States

39. Growing demand for natural gas, crude, and crude products will continue to fuel investment in the United States pipeline grid. In recent years, Master Limited Partnerships (MLPs) have accounted for a large percentage of United States pipeline investments. In 2006, over 50 MLPs, 80 per cent of which were associated with oil/gas pipelines and natural resources, were trading in the market with a market capitalization of US$ 80 billion.[5] MLPs, which are publicly traded limited liability partnerships, offer tax advantages in the form of a one-time investor tax, rather than having a dividend taxed at the corporate and personal level. MLPs are required to receive at least 90 per cent of their revenue from a specified list of sources that includes income and gain from commodities or commodities futures and income and gain from mineral or natural resources activities.

(f) European Pipelines

40. In comparison to the United States, Europe faces more security issues with regard to pipeline development, particularly in natural gas. Whereas the United States has enjoyed a generally secure, uninterrupted supply of piped natural gas from reliable, low-risk suppliers, Europe has faced an increasing number of disputes with supply counter-parties. The recent conflict between the Russian Federation and Ukraine is but one example.

41. Many of the current European pipeline developments are massive in scale and will require multiple sources of financing. The Nord Stream pipeline, owned by Gazprom, E.ON, and Wintershall, is expected to cost upwards of € 5 billion. The consortium has already faced financing problems, as the European Investment Bank stated in February that opposition from member states precludes the bank from investing in the project.[6]

(g) LNG Regasification

42. Both the United States and Europe are net importers of gas and rely largely on pipeline imports to cover the demand-supply gap. However, LNG imports are increasingly being sought to augment supply and to ensure security of supply through source diversification.

43. In the United States and Canada, current regasification capacity, which stands at approximately 42 million tons per annum (mtpa), does not exceed a 50 per cent utilization rate. Figure 3 shows supply of LNG versus regas capacity in North America. In the United States there is an additional 70.2 mtpa under construction, which is projected to meet regas capacity requirements for at least the next five years.

44. In Europe, existing capacity stands at 61 mtpa, which in 2006 achieved utilization rates of 60 to 70 per cent. An additional 31.3 mtpa of regasification capacity is under construction, and a further 25 new terminals are proposed for development.

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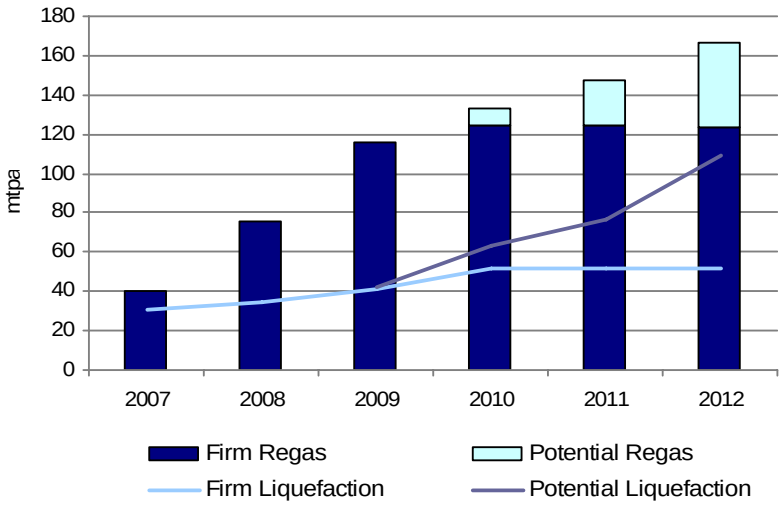
[5] http://www.streetauthority.com/cmnts/cp/2006/08-30.asp
[6] http://www.reuters.com/article/latestCrisis/idUSL08264455

45. Terminal sponsors have a number of financing methods available to raise capital for new developments. In comparison to more costly liquefaction projects, regasification terminals are relatively less expensive per unit and have been financed through corporate resources by the larger utilities to assure access to supply. However, a number of new developments in the United States and Europe are seeking project financing to finance greenfield developments. In many of these projects, a tolling model is employed, whereby the terminal owner is paid a capacity charge for converting LNG to gas. Non-recourse financing is raised on the back of the Terminal Use Agreement signed between the terminal owner and the gas/LNG owner. Tolling models place a priority on signing agreements with strong counter-parties.

Figure 3: LNG Supply versus regas capacity in North America



Source: Taylor-DeJongh estimates

2. Emerging Energy Hubs

46. In the midstream and downstream markets, the emerging energy hubs in Africa, the Middle East, and Asia share in general two common traits: a large projected growth in midstream/downstream capacity, and an environment in which there remain impediments to private foreign investment.

(a) Electric Power

47. The emerging regions highlighted in this paper – Africa, the Middle East, and Asia – will require 2,375 GW of additional and replacement capacity over the next 25 years. Of this amount, China accounts for 1,089 GW, or nearly half of the total capacity requirement. China by far outstrips any other single country's power requirements. The additional capacity in these regions will require an investment of over US$ 2.3 trillion (US$ 5.7 trillion when considering transmission and distribution) over 25 years.[7]

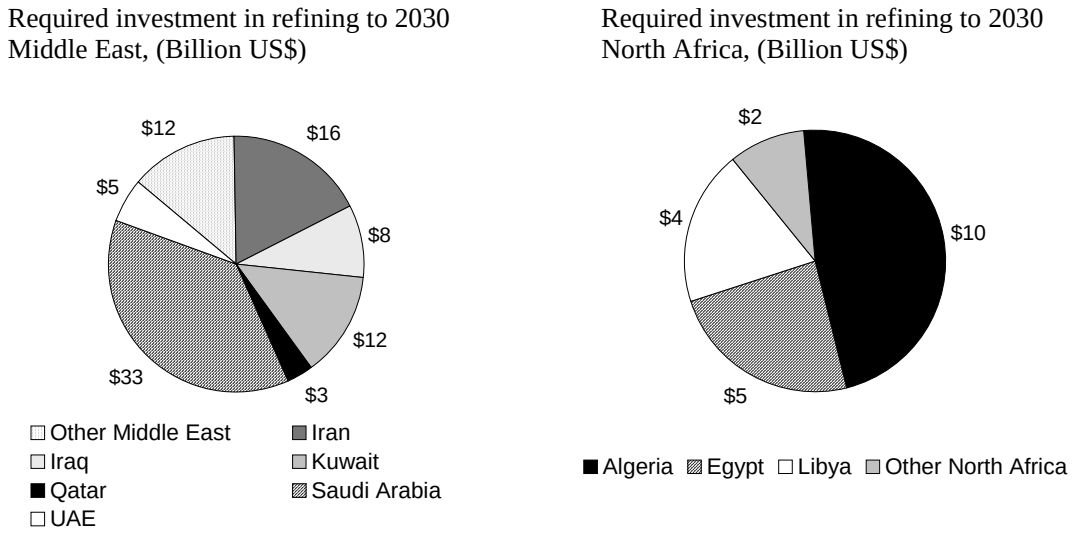
[7] IEA World Energy Outlook 2006

(b) Refining

48. New refining developments will shift away from traditional downstream markets in Europe and North America, due in large part to permit requirements and other regulatory issues, and focus on those countries with access to cheap feedstock, such as the Middle East and Africa or in new demand centres, such as China.

49. The Middle East and African regions will require new investment of approximately US$ 110 billion or US$ 4 billion a year through 2030 (figure 4). Investment will be concentrated in the Middle East (US$ 89 billion, making it the main exporter of petrol, diesel, heating oil, and jet fuel), with North Africa requiring approximately US$ 21 billion, as shown in figure 4. The majority of these funds will need to be invested by 2010. Saudi Arabia represents the largest volume of projects, with an expected 12.5 million b/d additional capacity expected over the next four years.

Figure 4: Required investment in refining to 2030 in the Middle East and North Africa

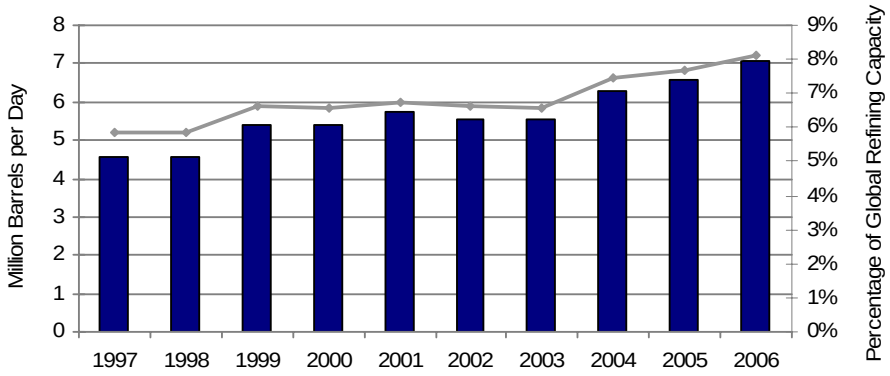


Source: International Energy Agency

50. China and India will be the other focal points for refinery growth. The Chinese Government has shown a strong interest in developing the domestic refining market rather than relying on imported products. Over the past decade, Chinese refinery capacity has increased by 2.4 million b/d, equivalent to a 56 per cent increase, making it the largest growth market for refining in the world (figure 5).

51. The next wave of pipeline developments (both gas and oil) is likely to cost between US$ 100 and US$ 200 billion. Much of the anticipated pipeline capacity growth (nearly 50 per cent) will be focused in Africa, the Middle East, and Asia. In most cases, pipelines in these regions will have to cross/transit multiple countries with varying degrees of political risk. Many of these new developments will focus on linking new oil and gas developments in the Russian Federation to markets to Europe and Asia.

Figure 5: Refining capacity in China



Source: British Petroleum

(d) Pipelines

52. Recent political challenges surrounding pipelines, such as the Chad-Cameroon pipeline dispute and the halting of Russian gas supplies to Ukraine, will increase the challenge of attracting investment in new developments.

(e) Liquefied Natural Gas (LNG) – Liquefaction and regasification

53. By 2010, it is anticipated that 90 to 105 mtpa of liquefaction capacity will be added, the overwhelming majority of which will come from Africa, the Middle East, and Asia. Costs for greenfield liquefaction plants have escalated dramatically in recent years and are currently running from US$ 400/tpa in low-cost environments to upwards of US$ 900/tpa in high-cost/high-risk regions such as Nigeria. It is estimated that up to US$ 100 billion in capital will be needed to bring this additional capacity on line.

54. In the regasification sector, China and India have captured most of the attention, with aggressive plans to expand capacity. China alone is planning to expand capacity by 35 to 40 mtpa by 2012 and has announced at least 10 regasification projects. Supply for these terminals will most likely come from Indonesia, the Islamic Republic of Iran, Malaysia, and Australia (with the Russian Federation a potential supplier as well). India plans to expand its current 6.1 mtpa of capacity with an additional 9 mtpa by 2012. At roughly US$ 200/tpa in the present market, China and India would require almost US$ 10 billion to meet projected expansions.

3. Methods of Financing Projects in Emerging Energy Hubs

55. As previously highlighted there are a number of sources of finance available to project developers in the United States and Europe. There is no doubt that the same sources of finance will be investing in developments in the emerging energy hubs as well. However, the higher levels of risk associated with changing political and regulatory environments means that these investments must be properly structured so as to allocate these added risks to those parties best positioned to accept them.

56. In some sectors, such as power development in China, the structure of the market and the size of the investments at the project level will push investors, either state or private, towards equity financing. However, for a significant percentage of the larger-scale projects, such as LNG, refineries, and pipeline developments, debt will have to be raised to help fund large capital outlays. For these capital-intensive investments, particularly in the emerging markets, the use of project financing (i.e. non-recourse debt financing) has remained a popular method of raising debt. Project financing entails the raising of debt secured against the future cash flow of a specific project. After the project is up and running, the lenders typically do not have recourse to sponsors beyond the shares in the special-purpose project company.

(a) Benefits, Drawbacks, and Lenders' Concerns

57. Project financing, as a method of raising capital, has a number of benefits:

(a) Eliminates cross-subsidies: Each project in the energy value chain must be viable and self-supporting on a stand-alone basis.

(b) Minimizes impact of project failure: For the sponsors, exposure is limited to the value of the equity investment. Lenders are prevented from pursuing a claim against the sponsor's other assets or cash flows.

(c) Risk allocation: A well-structured project allocates each risk to the party that is best positioned to manage it.

(d) Optimizes cost of capital: A project's risk profile and capital structure may be such that the project's cost of capital is lower than that of the sponsor.

(e) Maximizes debt capacity: A well-structured project can attain a high level of gearing (up to 90 per cent). Project debt is generally not counted on the balance sheet.[8]

58. The drawbacks of project financing include:

(a) High transaction costs: The complexity of multi-party negotiations and documentation leads to high costs for lawyers, financial advisers, and expert consultants.

(b) Lengthy development schedules: Putting in place the numerous contracts and requirements for a project financing can take up to 2 to 3 years from project identification to financial close.

(c) Constraint on business activities: Loan documentation will provide the lenders with intrusive rights over how the project is run.

(d) Administrative cost of loan compliance.

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[8] Reporting of project debt varies among jurisdictions. In most cases, project debt is reported in the notes accompanying the financial statements.

59. Due to the limited nature of the recourse, the lenders require that the project is tightly structured so as to ensure that the project will produce fairly predictable cash flows, and hence be able to service its debt. Among the lenders key concerns in an energy project is market price risk. Due to the highly volatile nature of the hydrocarbon commodity markets, exposure to price risk limits the accuracy of future cash flow estimates. For this reason, lenders are often conservative in their estimates of future cash flows of energy projects. For example, debt service ratios required by the lender banks in a project exposed to commodity price risk are significantly higher than in projects that are independent of commodity price risk.

60. The lenders will take comfort in strong contracts underpinning the engineering, procurement, and construction; operations and maintenance; product sales and purchase; feedstock supply; and government licenses.

4. Key Issues for Raising Midstream/Downstream Investment in Emerging Energy Hubs

(a) Private Sector Investment is Essential

61. Governments and NOCs will not be able to develop required future midstream and downstream capacity alone. Even in a cash-rich environment, the capital costs of major projects exceed the budget of many NOCs. Further, the technical capacity for developing the next generation of refining, LNG, and pipelines is lacking in many resource-rich countries. This will of course be of issue in developing a functioning, operationally sound project. But it will also be a limiting factor in raising debt financing. A lender will not provide capital to a project unless it is assured that the sponsor(s) has the technical knowledge and experience to effectively manage the construction and operation of the plant.

62. In many instances, host governments have acknowledged that private investment is required to fund expansion. In Saudi Arabia, for example, Saudi Aramco has partnered with IOCs (and other NOCs) in a massive effort to expand the Kingdom's refining capacity. Projects include:

(a)	Rabigh Expansion with Sumitomo	425,000 b/d
(b)	Yanbu Export Refinery with ConocoPhillips	400,000 b/d
(c)	Jubail Expansion Refinery with Total	400,000 b/d

63. In the liquefaction sector, multiple examples of NOC-IOC joint development, including projects in Qatar, Egypt, Algeria, Oman, and Indonesia, show the importance of foreign investment and expertise in bringing new liquefaction capacity online.

(b) Long-Term Projects Require Stable Investment Regimes

64. Most large-scale midstream and downstream projects have long-term investment horizons. The combined development and construction period can reach up to six years in length, and high capital costs often mean lengthy payback periods. For this reason, ensuring a solid fiscal and licensing package at the project level, and a steady regulatory regime at the government level, is essential in attracting necessary investments.

65. Among the examples of project failures involving unstable investment regimes include the Dabhol combined LNG receiving terminal and power project. The Dabhol Power Company's inability to cover its contractual obligations and the government's refusal to honour its guarantees left a negative legacy in the Indian market place. More than five years have passed since the Dabhol project ran afoul, and the government continues to struggle with assuaging foreign investors' concerns over market stability.

(c) Midstream and Downstream Projects are Dependent Upon Their Upstream Counter-Parties for Success

66. Processing facilities, such as refineries and LNG plants, can only succeed if they are coupled with a strong, reliable upstream counter-party. In resource-rich countries, a government's ability to ensure fiscal and regulatory stability must extend beyond the plant to the upstream supplier.

V. CONCLUSIONS AND RECOMMENDATIONS

67. Capital, on a global basis, will be available for allocation to investment in the energy sector. However, within that sector, capital will flow only to the companies, projects, and countries where fair and balanced risk/reward ratios exist. Political decisions (what IOCs and their bankers call "above ground risk") will impact favourably or unfavourably the flow of capital needed for energy investment.

68. Tightness will continue in the oil market as investment in new capacity will largely only meet incremental demand. Increasingly, NOCs will be underinvested in long-term capacity, with the Islamic Republic of Iran, Venezuela, and the Russian Federation failing to meet the required additional capital requirements. While Saudi Aramco will continue to invest sufficient capital in the midstream and downstream, its ability to materially increase upstream production is still an open question. There will be continued erosion of the traditional reserve cushion, and various political instabilities will add additional premiums to global oil prices.

69. On the downstream side, China needs to allocate massive capital for the refining and power generation sectors, and it will increase the pricing pressure for acquiring oil and gas reserves to feed its raw energy demand.

70. Energy production and consumption are intertwined. Resource rich countries rely on exports for a substantial portion of fiscal revenues and have pressing investment and technological expertise shortages. Clarifying the treatment of FDI in providing greater economic diversification for energy rich countries will be important. Further, the nature of long-term reinvestment of upstream-generated revenues will require state actors to review their role in an integrated energy chain. Promoting greater private-public sector investment cooperation will be dependent on articulating the advantages of open access investment opportunities to all sides.

71. Holding reserves of raw energy will not be sufficient to attract the capital to produce and utilize that energy, unless there is balanced and transparent treatment of that capital and its yields. Private capital will flow where it is treated fairly and transparently and has a reasonable opportunity for a balanced return on the risks assumed. Investors will weigh the risk and

rewards of investments but will avoid countries where the ability to assess a proper return on investment is overcome by material disincentives. Governments should work towards reducing impediments to capital flows and pursue policies that provide a level playing field for all investors. Reducing opacity in the banking, regulatory, and legal system will ensure that investors are able to properly assess new opportunities.

72. Both the established United States and European markets and the emerging energy hubs will require large capital investments to maintain forecasted growth in the energy sector. In order to meet this projected demand for capital, all sources of funds will be required. However, project developers in Africa, the Middle East, and Asia will be challenged with raising capital in a continually evolving political and regulatory environment. Governments should strive to achieve a fiscal and regulatory environment in which multiple sources of finance are supported. Encouraging the growth of efficient capital markets and allowing the free exchange of funds will promote the development of increasingly sophisticated methods of financing in the hydrocarbon sector, which in turn will enhance global energy security.
